BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NOS. 050045-EI AND 050188-EI
FLORIDA POWER & LIGHT COMPANY

JULY 28, 2005

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY
AND
IN RE: 2005 COMPREHENSIVE DEPRECIATION STUDY BY FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY & EXHIBIT OF:

ROSEMARY MORLEY

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Q. Please state your name and business address.

A. My name is Rosemary Morley. My business address is 9250 West Flagler Street, Miami, Florida, 33174.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring an exhibit to your rebuttal testimony?

A. Yes. I am sponsoring an exhibit consisting of seven documents, RM-11 through RM-17, which is attached to my rebuttal testimony.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address testimony from the following witnesses: Mr. Stephen J. Baron on behalf of the South Florida Hospital & Healthcare Association (SFHHA), Mr. James T. Selecky on behalf of the Commercial Group, and Dr. Dennis W. Goins on behalf of the Federal Executive Agencies (FEA). I also discuss, to a lesser extent, the panel testimony of Ms. Teresa Civic and Mr. Jess Galura on behalf of the Commercial Group. The issues discussed in my rebuttal testimony include the cost of service methodology, the allocation of the revenue increase, the rate treatment for the GSD-1, GSLD-1, and GSLD-2 rate classes, the

Commercial/Industrial Load Control (CILC) rate design, the Optional High Load Factor rate design, and the 2007 Turkey Point Unit 5 adjustment. I also address certain claims made regarding the Company's rates, particularly in terms of the rates available to commercial customers. I will begin by addressing the cost of service methodology.

COST OF SERVICE METHODOLOGY

Q. Please summarize FPL's cost of service methodology and its results as presented in your direct testimony.

A. FPL consistently followed Commission precedent and sound ratemaking principles in developing its cost of service study. As I discuss in my direct testimony, the results of this study clearly indicate that the rates for many classes, particularly those applicable to medium and large commercial/industrial (C/I) customers, are below their cost to serve. Mr. Baron and Mr. Selecky have proposed alternative cost of service methodologies intended simply to shift costs away from their clients in these medium and large C/I rate classes and onto other customers. The intervenors have failed, however, to make a compelling case for replacing the cost of service methodologies presented in my direct testimony.

Q. What cost of service methodology did FPL propose for allocating production plant?

A. FPL used the 12 CP and $1/13^{th}$ methodology in allocating production plant.

Q. What does Mr. Baron propose in terms of production plant?

A. Mr. Baron proposes to use the average of the single highest monthly summer peak ("Summer Peak") and the single highest monthly winter peak ("Winter Peak") in allocating production plant.

Q. What do you conclude as a result of your review of Mr. Baron's proposal to use an average Summer/Winter Peak in allocating production plant?

A. The Commission should reject Mr. Baron's proposed use of an average Summer/Winter Peak for the following reasons:

- The average Summer/Winter Peak allocation methodology mischaracterizes the generation planning process;
- The Summer Peak and Winter Peak are not consistently the highest two monthly peaks of the year;
- The data fail to confirm the patterns in coincident peak demands by rate class that Mr. Baron claims supports an average Summer/Winter Peak allocation methodology;
- The average Summer/Winter Peak allocation does not send a better price signal than the 12 CP and 1/13th methodology;
- The average Summer/Winter Peak allocation methodology would allocate no production costs to certain rate classes even though all rate classes receive the benefit of FPL's generating capacity.

Q. Why does the average Summer/Winter Peak allocation mischaracterize FPL's generation plan?

A. Mr. Baron states that "the requirement to meet the summer and winter peak demand is driving the capacity resource addition on the system." (Direct Testimony page 29, lines 2-3). This characterization of the generation plan, however, is faulty on three counts. First, Mr. Baron completely ignores the influence fuel savings has on the type of generating units added. While the decision to add additional MW of generation capacity is driven by load requirements, the type of generation capacity added - and thus the total cost of the unit additions - is influenced by the number of hours the units are expected to run. Indeed, if MW capacity were the only consideration in the generation plan, the Company's resources would consist solely of gas turbine peaking units. This is clearly not the case, nor should it be.

Q. What is the second way in which an average Summer/Winter Peak allocation methodology mischaracterizes the generation plan?

The peak demands driving the decision to add additional generation capacity are not based on an average of the Summer Peak and Winter Peak. While it is true that FPL must maintain a 20% reserve margin on both the annual Summer and annual Winter Peaks, the impact each peak has on the planning process is far from equal. Dr. Sim, FPL's Resource Assessment and Planning Supervisor, noted in Docket No. 040206-EI, "For a number of years now, FPL's projected need for additional resources has been driven by the Summer reserve margin criterion." (Direct Testimony, page 7, lines 19-20). Indeed, Mr. Baron indirectly, and perhaps inadvertently, acknowledged this in a footnote on page 30 of his testimony which states, "However, based on the Company's resource plan, FPL is generally adding capacity that maintains a 20% reserve margin in the *Summer* [emphasis added]." Dr. Green provides additional support on this issue in his rebuttal testimony.

Q. Did the Winter Peak drive the need to add the Turkey Point Unit 5?

A. No. As clearly outlined in Docket 040206-EI, the need for the Turkey Point Unit 5 addition was based on the summer reserve margin criterion, not on some average of the summer and winter reserve margins.

Q. If the summer reserve margin criterion has been driving the Company's need for additional capacity why does Mr. Baron propose an allocation based on the average Summer/Winter Peak?

A. Quite simply, by using the average Summer/Winter Peak, Mr. Baron allocates significantly less costs to the customers he is representing and more costs to the residential (RS-1) customers. As shown in Document No. RM-11, for many of the larger rate classes, an allocation based on the Summer Peak methodology generally approximates the allocation based on a 12 CP methodology. For example, the share of production costs allocated to RS-1 is 59.8% under both the 12 CP and the Summer Peak allocation methodologies. Likewise, the share of production costs allocated to GSLD-1 is 8.5% under the 12 CP methodology and 8.3% under a Summer Peak methodology. Under the average Summer/Winter Peak methodology, however, RS-1 share of costs increases to 65.5%. The opposite pattern is found in the larger commercial/industrial rate classes. With an allocation based on the average Summer/Winter Peak methodology, GSLD-1's share of costs declines to 7.3%.

Q. Why does the Winter Peak have such a dramatic impact on the cost allocation by rate class under the average Summer/Winter Peak allocation methodology?

A. Under the average Summer/Winter Peak allocation methodology, the Winter Peak determines 50% of the allocation by rate class. This undue emphasis on the Winter Peak has a dramatic impact on the allocation by rate class because the timing and characteristics of the Winter Peak are so different than that of the other eleven monthly peaks. Most of FPL's monthly peaks tend to occur around the 3:00 PM to 6:00 PM window year round. This is not the case, however, when the Company experiences a cold weather peak, which is usually limited to one monthly peak a year and defines the Winter Peak. The Winter Peak typically happens in the early morning hours, a time when many businesses are closed and the heating requirements of residential customers are at their highest. Hence, residential customers are responsible for a larger share of the Winter Peak than they are of the Summer Peak or the other monthly peaks of the year.

Q. What is the third way in which the average Summer/Winter Peak methodology mischaracterizes the generation plan?

A. In addition to the reserve margin, another criterion in the generation plan is maintaining a loss-of-load probability (LOLP) of 0.1 days per year or less. The LOLP criterion considers peak loads year round and therefore, would not be consistent with a method which considers only two peak hours per year.

Q. What other arguments does Mr. Baron make in support of the average Summer/Winter Peak allocation?

A. Mr. Baron argues that the magnitude of FPL's Summer Peak and Winter Peak are substantially higher than that of the other ten monthly peaks. In support of this, Mr. Baron presents two charts, one based on 2003 and another based on 2005, designed to suggest that the Summer and Winter Peaks are always head and shoulders above the other monthly peaks (Direct Testimony, page 31, Figure 3). A longer view, however, suggests a different story. While the Summer Peak is almost always the highest or second highest monthly peak of the year, the magnitude of the Winter Peak relative to other monthly peaks is much more variable over time. For example, in 2004 the Winter Peak was lower than six of the monthly peaks for the year. A similar pattern was experienced in 2002 and 1998. Mr. Baron's methodology ignores these other monthly peaks which are in many cases higher than the Winter Peak. In total, the Winter Peak was the highest or second highest monthly peak in only four out of the last ten years. This is shown in Document No. RM-12.

Q. What does the analysis shown in Document No. RM-12 suggest in terms of the method used to allocate production plant?

A. The analysis in Document No. RM-12 shows that selectively including certain peak months while excluding others can become an arbitrary exercise. In addition, picking and choosing among monthly peaks is unlikely to produce results that consistently reflect cost causation over time. One of the advantages of the 12 CP and 1/13th methodology is that it does not require arbitrary judgments as to which monthly peaks are important and which are not.

Q. What patterns in coincident peak contributions by rate class does Mr. Baron allege?

A. Mr. Baron provides a chart on page 26 of his testimony which allegedly shows that residential customers (RS-1) have experienced disproportionate increases in their average Summer/Winter Peak contributions relative to their 12 CP contributions. Mr. Baron then presents a chart on page 27 designed to suggest that GSLD-1's average Summer/Winter Peak contributions have consistently lagged behind its 12 CP contributions. It appears that Mr. Baron is seeking to demonstrate that the incremental coincident peak demands of residential customers are driving capacity additions while the incremental coincident peak demands of GSLD-1 customers are occurring in off-peak months which, Mr. Baron claims, have no impact on generation costs (Direct Testimony, page 28, line 4-10.)

Q. What is your assessment of the patterns in coincident peak demands by rate class that Mr. Baron alleges?

A. As with any graphic analysis of a trend, the starting point, if not selected carefully, can influence the results. In this case, Mr. Baron has selected 1998 as the starting point in an effort to demonstrate an alleged pattern of increasing Summer/Winter Peak demands on the part of RS-1 customers. One might assume that the Summer and Winter Peaks of 1998 were typical of past peaks, but that was not the case. The 1998 Winter Peak, which accounts for 50% of the average Summer/Winter Peak, was an anomaly. Indeed, the 1998 Winter Peak was not a cold weather peak at all, but was the result of a bizarre November heat wave. If a more typical Winter Peak is selected, the trend that Mr. Baron alleges all but evaporates. As shown in Document No. RM-13, the relationship between RS-1's 12 CP versus its average Summer/Winter Peak contribution in the 2006 test year is generally the same as it has been historically based on data since 1995. More importantly, RS-1's contribution to the critical Summer Peak has generally tracked its 12 CP contributions.

Q. What does Document No. RM-13 suggest in terms of the GSLD-1 rate class?

A. Document No. RM-13 shows that the GSLD-1's contribution to the critical Summer Peak is typically higher than its 12 CP contribution - sometimes by a significant margin. This fact clearly contradicts Mr. Baron' claim that GSLD-1's incremental coincident peak demands have been concentrated in the off-peak months (Direct Testimony, page 28, lines 4-10).

Q. Does the average Summer/Winter Peak allocation send a better price signal than the 12CP and 1/13th methodology?

A. No. The 12 CP and 1/13th methodology more accurately reflects the generation plan than does the average Summer/Winter Peak allocation because 1) it recognizes that the type of generation unit selected is influenced by the kWh the unit is expected to run, 2) it better reflects the influence of the summer reserve margin, and 3) it recognizes that capacity must be available throughout the year to meet peak demand consistent with the use of the LOLP criterion in the planning process. Accordingly, the 12 CP and $1/13^{th}$ methodology will send a more appropriate price signal than an average Summer/Winter Peak allocation methodology.

Q. Are there any other factors which should be considered in determining the appropriate method of allocating production plant?

A. Yes. The Commission has long recognized that one of the advantages of the 12 CP and $1/13^{th}$ methodology is that it ensures that each rate class pays some portion of the production plant it uses (Docket No. 820097-EU, Order No. 11437.) By contrast, methods such as the average Summer/Winter Peak allocation which are limited to one or two hours a year can result in some rate classes contributing nothing towards production plant even though such rate classes clearly benefit from – and rely on – the system's production resources. This is evident in Document No. RM-11 which shows that three rate classes are allocated no production plant costs using an average Summer/Winter Peak allocation.

Q. Do you have any other comments regarding Mr. Baron's proposed use of the average Summer/Winter Peak allocation?

A. Yes. The use of a 12 CP and $1/13^{th}$ methodology has an extensive history of regulatory approval in Florida and over the years the Commission has clearly articulated why it believes the methodology is appropriate. Accordingly, it would be reasonable to expect that consideration of an alternative method would be made only to the extent that a clear and compelling case is made for that alternative method. After all, Mr. Baron himself found the 12 CP and 1/13th method "reasonable" for FPL's use as recently as 2002 (Docket 001148-EI, Direct testimony of Stephen Baron, page 6, line 20). After reviewing the arguments Mr. Baron now presents in support of an alternative methodology, one based on an average Summer/Winter Peak, it is obvious that a clear and compelling case has not been made. The Commission should approve the 12 CP and 1/13th methodology as proposed by the Company.

Q. **Are there any other cost of service issues raised in the intervenors' testimony to which you would like to respond?**

A. Yes. I would like to respond to Mr. Baron's and Mr. Selecky's advocacy of the minimum distribution system (MDS) or zero intercept system method for allocating distribution plant.

Q. **How does the MDS method compare with the Company's proposed method of allocating distribution plant?**

A. FPL's methodology classifies meters, service drops, and primary pull-offs as customer-related and classifies the remaining balance of distribution plant as demand-related. Thus, under FPL's methodology substations, poles, conductors (excluding primary pull-offs) and transformers are classified as demand-related and are allocated among the rate classes using various measures of peak demand. The MDS method classifies a portion of poles, conductors and transformers as customer-related and allocates these costs among the rate classes based on the number of customers. The MDS method determines the customer-related portion of these facilities on the basis of a hypothetical distribution system constructed to serve the minimum load requirements of customers. Under the MDS method, minimally sized transformers, poles, and conductors are used as the basis for constructing this minimum load requirements system. A variant of the MDS method, the zero intercept method uses statistical extrapolation to determine a hypothetical customer-related portion of poles, conductors and transformers.

Q. What impact would the MDS method have on the allocation of costs by rate class?

A. By reclassifying demand-related costs as customer-related, the MDS method would increase the amount of distribution plant allocated to residential and very small commercial customers. Larger customers, such as those in the GSLD-1 rate class, would benefit through a reduced allocation of costs.

Q. What do you conclude from your review of Mr. Selecky's and Mr. Baron's testimony on the MDS method?

A. The Commission should reject the use of the MDS method for the following reasons:

- The Commission has consistently rejected the use of the MDS method for investor owned utilities and a compelling case for ignoring that precedent has not been made in this case;
- The MDS method presumes a type of electric system and a method of planning which is not reflective of FPL's distribution system;
- The MDS method assumes unique characteristics on the part of the electric utility, including low customer density, highly sporadic

loads, a high ratio of accounts per customer location, and an inability to adequately recover costs absent the use of the MDS method, none of which are applicable to FPL;

- The economies of scale argument made by Mr. Baron ignores the impact of density, diversity and double-counting;
- Mr. Baron has inappropriately estimated the impact of the MDS method.

Q. **Has the MDS method ever been approved for an electric investor owned utility (IOU) in Florida?**

A. No. The issue has been considered by the Commission numerous times and has been consistently rejected, most recently in 2002 (Docket No. 010949, Order No. PSC-02-0787-FOF-EI). Moreover, the Commission's findings regarding the MDS method in that order are applicable in this case, as I address in the discussion below.

Q. **Why does the MDS method presume a type of electric system and a method of planning which is not reflective of the FPL distribution system?**

A. The MDS method assumes that a certain investment in transformers, conductors and poles is required solely as a result of connecting customers to the electric system. Consequently, the MDS method is based on a set of distribution facilities designed to service the zero or minimum load requirements of customers. As the Commission states in Order No. PSC-02-0787-FOF-EI, "The concept of a zero load cost is purely fictitious and has no grounding in the way the utility designs its systems or incurs costs because no utility builds to serve zero load." Moreover, the Commission's analysis is consistent with FPL's distribution planning. The central criterion used in planning the FPL distribution system is kW load requirements, not customers served.

Q. Does this mean that the need to serve individual customers never influences distribution plant additions?

A. No. There are certainly cases where line extensions are required to serve specific customers. This is where a strong and consistently enforced contribution in aid of construction (CIAC) policy comes into play. As outlined in the Florida Administrative Code (FAC 25-6.064), customers are required to pay for the cost of any line extension to the extent that the expected revenues do not offset the cost of the line extension. In this manner, customers with "minimum load requirements" must pay for the cost of any line extensions required to service them. This is a far more equitable outcome than the cost allocation resulting from the MDS method since the specific customers necessitating the line extension bear the cost.

Q. Would the requirement to pay a line extension CIAC be limited to large commercial/industrial customers?

A. Not at all. A CIAC would be required in any case where the expected load and revenue does not offset the required investment. In fact, the CIAC line extension formula is routinely applied to new residential subdivisions.

Q. Has a MDS method ever been approved for any electric utility in Florida?

A. The sole case in which the MDS method was approved involved an electric cooperative, the Choctawhatchee Electric Cooperative, in 2002.

Q. Does the Commission decision with regard to the Choctawhatchee Electric Cooperative in any way alter its policy against the MDS?

A. No. The Commission decision (Docket No. 020537-EC, Order No. 02-1169-TRF-EC) made it clear that the Choctawhatchee Electric Cooperative possessed "unique characteristics" which justified this departure from precedent.

Q. Are these "unique characteristics" shared by FPL?

A. No, they are not. First, the Commission cited Choctawhatchee Electric Cooperative's low customer density. The Commission noted that the Cooperative has a customer density of 10 customers per square mile while most IOUs have a density of 54 customers per square mile or greater. As I present in Document No. RM-14, FPL's density is 149 customers per square mile or roughly 15 times greater than that of Choctawhatchee Electric Cooperative.

Q. Why is customer density a consideration in evaluating the appropriateness of the MDS method?

A. Pockets of geographically isolated customers could require a greater number of poles and a longer span of conductors to provide service than would be the case in more urban settings. Thus, a rural utility could find that the MDS method adequately reflects their planning process. FPL, on the other hand, has a high customer density. As shown on Document No. RM-14, the Company's customer density is dramatically higher than that of a rural cooperative. In fact, the Company's customer density is even high relative to other IOUs. Moreover, FPL's customer density has increased significantly over time and is projected to continue increasing over time as our load grows.

Q. Does customer density influence any distribution facilities besides poles and conductors?

A. Yes. The MDS method assumes that there is some minimally sized transformer required to connect customers regardless of their load. In utilities with very low customer density, the notion of a minimal load transformer may have some validity because in sparsely populated rural areas there is usually one transformer per customer. By contrast, in more urban areas several customers may be served from one transformer. This is certainly the experience at FPL where serving 5-6 residential customers or more from a single transformer is standard.

Q. What other "unique characteristics" did the Choctawhatchee Electric Cooperative have?

A. The Commission noted that the Cooperative's rural service territory experiences greater seasonal variability than is typically found in more urban electric utilities. The Commission noted that the cooperative supplies service to "a significant number of barns, stock tanks, electric fences, hunting cabins, and vacation homes." Proponents of the MDS method suggest that highly sporadic loads may support the use of this method because a rate design based on relatively low customer charges and high energy charges may not adequately recover costs.

Q. Are FPL loads highly sporadic in this manner?

A. No. Less than 5% of residential accounts consume a minimal amount of electricity, i.e. 100 kWh or less, in any given month.

Q. Are highly sporadic loads cited as a reason in this case for adopting the MDS method?

A. Yes. Mr. Baron states that there are a significant number of vacation homes in the Company's service territory (Direct Testimony, page 47, lines 14-16). Mr. Baron cites a hypothetical example of a single family home used 50 days a year and claims that this type of customer would not be allocated any distribution plant costs under the Company's cost of service methodology unless the customer happens to be on at the time of the rate class's group peak. Mr. Baron, however, offers no evidence whatsoever for the alleged significance of vacation homes in FPL's service area. In fact, the data show that less than 5% of FPL's residential accounts have minimal loads (i.e. 100 kWh or less) in any given month. The percentage of accounts with consistently minimal loads (i.e. under 100 kWh per month for all but 50 days per year) would, by definition, be even less.

Q. Did the Commission offer other examples of the "unique characteristics" of the Choctawhatchee Electric Cooperative that made the MDS method appropriate?

A. Yes. The Commission noted that the ratio of accounts per customer location was quite high. The cooperative's rural customer base was cited as the reason for this high ratio. For example, a farm could have a residence, a barn and an electric fence all on different meters. Assuming such a configuration, a customer's total load would be divided among multiple accounts, thus increasing the utility's connection costs. Lastly, the MDS method was approved in part because of the cooperative's financial hardships under the assumption that higher customer charges would help stabilize revenues. Again, neither of these two reasons would be applicable to FPL.

Q. Given the background on the MDS method you've provided, what arguments do Mr. Baron and Mr. Selecky make for advocating such a dramatic change in the Commission policy regarding the allocation of distribution plant?

A. Mr. Baron states that the MDS is necessary because of what he refers to as the economies of scale in certain distribution facilities (Direct Testimony, page 41, lines 3-4). The economies of scale argument also appears to be the rationale behind the schematic diagram Mr. Selecky presents on page 16 of his testimony.

Q. Do you find this argument convincing?

A. No, I do not. The MDS method shifts all benefits from economies of scale to the larger customers even though there are economies of scale in serving residential customers. In dense urban areas not only are multiple residential customers frequently served off the same transformer but the size of such a transformer is frequently comparable to that used for commercial customers. The diversity of residential customers' loads also creates economies of scale. Because each residential customer's maximum demand will not coincide exactly with other customers' on the same transformer engineering procedures dictate that transformers serving multiple residential customers need not be sized to serve the sum of every customer's maximum demand. Mr. Selecky's schematic on page 16 of his testimony would suggest that a new transformer is required for every three residential customers added to the system. In reality, distribution planners can and do routinely add new customers to existing transformers because of the diversity of residential loads. By contrast, no such diversity is applicable to a large commercial customer served from a single transformer.

Q. Are these the only problems with the MDS method as it is applied to transformers?

A. No. Another problem with the MDS method as espoused by Mr. Baron and Mr. Selecky is that it would double count the kW loads of residential and the smallest commercial customers for the investment in transformers associated with their so-called minimal load requirements.

Q. Why does this double counting occur?

A. This double counting occurs because the RS-1 and the smallest commercial rate class (GS-1) are first allocated the cost of the so-called minimum load transformers based on the number of customers. The remaining cost of transformers is then allocated to RS-1 and GS-1 on the basis of their maximum customer peaks, with no adjustment for that portion of the maximum customer peaks which is provided under the minimum load transformer.

Q. Do Mr. Baron and Mr. Selecky offer any other arguments for applying the MDS method in this case?

A. Mr. Selecky claims that a number of other jurisdictions are using the MDS method (Direct Testimony, page 16, lines 3-7). The use of a cost of service methodology in a different jurisdiction should not be interpreted as the decisive factor supporting its application in Florida. Accordingly, the use of the MDS method by Gulf's sister company was not found to be a compelling factor in Order No. PSC-02-0787-FOF-EI. Mr. Baron and Mr. Selecky also claim that the NARUC Electric Manual endorses, if not requires, the use of the MDS method. However, as the Commission has already observed, the NARUC manual states that the choice of methodology will depend on the unique circumstances of the case (Docket No. 010949-EI, Order PSC-02-0787-FOR-EI, page 66).

Q. Do you have any other comments regarding the intervenors' support for the MDS method?

A. Yes. Mr. Baron has quantified the impact from the MDS method by applying the classification between demand and customer costs developed for Gulf Power Company to FPL's cost of service study (Direct Testimony, page 49, lines 2-5). Under the best of circumstances assuming that two electric utilities have an identical cost structure is problematic. In this case, using Gulf Power Company to illustrate the impact of the MDS method is particularly inappropriate. As discussed earlier, customer density has been recognized as a factor in evaluating the MDS method. As shown in Document No. RM-14, FPL's density of 149 customers per square mile exceeds Gulf's 54 customers per square mile by a factor of almost 3 to 1.

Q. Do you have any other comments regarding Mr. Baron's cost of service analysis?

A. Yes. On Table 6, page 51 of his testimony Mr. Baron shows the parity figures resulting from the average Summer/Winter Peak treatment of production plant combined with the MDS method for distribution plant. I am unable to confirm Mr. Baron's calculation and in no way endorse the use of either an average Summer/Winter Peak treatment of production plant or the MDS method for distribution plant. Nevertheless, I think it is important to point out that, even with the dramatic methodology changes Mr. Baron is advocating, a number of the larger commercial rate classes (GSLD-1, GSLD-2, and CS-2) remain below parity.

ALLOCATION OF THE REVENUE INCREASE

Q. Can you briefly summarize the Company's proposal on allocating the revenue increase?

A. Yes. As I discussed in my direct testimony, the Company proposes to move the majority of rate classes to within +/- 10% of parity. Because the Company's rates have not been adjusted to improve parity in more than twenty years there are widely disparate parities by rate class. For example, two rate classes, outdoor lighting (OL-1) and the standby service to customers below 500 kW (SST1-DST), are not even earning positive rates of return. In other words, these rate classes are not even earning enough to offset the operating expenses allocated to them, much less make any contribution to capital costs. Likewise, two other specialty service rates, namely street lighting (SL-1) and sports field lighting (OS-2), are earning less than 50% of the average rate of return. At the other end of the spectrum, other rates are earning 50% more than the average rate of return. The largest group in this regard is the GS-1 rate class which consists of the smallest commercial customers. The Company's proposal would provide an important – and necessary – step in addressing these discrepancies.

Q. What positions have the intervenors taken on this issue?

A. Each of the intervenors filing testimony on this issue, Mr. Baron, Mr. Selecky, and Dr. Goins, acknowledge the goal of moving rate classes closer to parity. However, the intervenors advocate a limit of 150% of the system average be applied to any rate class's increase. The intervenors argue that in past cases the Commission has relied on a rule-of-thumb that limits the increase to any rate class to no more than 150% of the system average increase.

Q. Does the Commission's past use of this rule-of-thumb dictate its use in this case?

A. No. The Commission has recognized that there may be circumstances in which the rule-of-thumb should not be applied. Specifically, in Docket 810136-EU, Order No. 10557, pages 29-30 (the "Gulf Case") the Commission rejected the use of the 150% rule-of-thumb. In that case the Commission ruled "we are departing from our policy in previous cases of limiting the increase to any one class to no more than 1.5 times the system average increase. Were we to apply that policy in this case, some classes whose present rates of return are above parity would receive an increase.

Thus, the greater equity lies in allocating the increase to those rate classes with substantially lower rates of return."

Q. What meaning do you ascribe to the Commission's reference to "the greater equity"?

A. That it is inherently fair and equitable to align each rate class's revenues with its cost of service. Limiting the revenue increase to any individual rate class to a certain threshold may appear to be equitable, but the benefits of doing so should be balanced against the added revenue burden other customers would be required to bear and the disparities in parity by rate class which would continue to perpetuate as a result. As the Commission found in the Gulf case, the revenue burden on other customers and the disparities in parity by rate class can be such that the use of the rule-of-thumb is inequitable.

Q. How did the parities by rate class in the Gulf case compare with FPL's in this filing?

A. The parity by rate class in the Gulf case ranged from 81% to 145%. By contrast, the FPL's cost of service study shows parities by rate class ranging from less than zero to in excess of 150%. Thus, the inequity resulting from the use of the rule-of-thumb would be far greater in this case than would have been in the Gulf case.

Q. If the rule-of-thumb were applied in this case which rate classes would have to shoulder a revenue increase in excess of their cost of service?

A. The RS-1 class, by virtue of its size and the fact that it is above parity, would end up shouldering a revenue increase in excess of its cost of service if the rule-of-thumb were applied in this case. The use of the rule-of-thumb would increase the target revenues required from RS-1 by $18 million or 8.4% more than the $214 million proposed in the Company's filing. Moreover, under the conventional rule-of-thumb the total base revenue increase for RS-1 would be only a fraction below the system average increase requested even though RS-1 parity at 106% is substantially higher than that of most other classes. In other words, under the rule-of-thumb there would be little effort to align costs and revenues in the RS-1 rate class, a class that represents almost 90% of our customers.

Q. Are there any other compelling reasons why the rule-of-thumb should not be applied in this case?

A. Yes. In past circumstances reasonable progress toward parity may have been achievable using the rule-of-thumb. For example, in Docket No. 830465-EI when the rule-of-thumb was last applied to FPL's rates, only one rate class was left with a parity index below 90%. By contrast, in this case, half of all rate classes would be left with a parity index below 90% if the rule-of-thumb were used.

Q. Do you have any other comments regarding the allocation of the revenue increase by rate class?

A. Yes. Mr. Baron advocates a uniform revenue increase across all rate classes (Direct Testimony, page 51, lines 6-8). The suggestion is based on the application of cost of service methodologies which I do not support and have already addressed. Nevertheless, even Mr. Baron's calculations show parity indices ranging from -54% to 618%. How such widely disparate parity indices "support the allocation of approved revenue increases on an equal percentage increase for all rate schedules" as Mr. Baron claims, is difficult to comprehend.

GSD-1, GSLD-1, AND GSLD-2 RATE CLASSES

Q. Have the intervenors raised any issues in terms of the treatment of specific rate classes?

A. Yes. Mr. Selecky objects to the Company's proposed rates for GSD-1, GSLD-1, and GSLD-2 rate classes. (Direct Testimony, page 23, lines 3-6).

Q. What are the GSD-1, GSLD-1 and GSLD-2 rate classes?

A. Currently, the Company has three different distribution-voltage demand meter general service rate classes depending on the customer's kW. They are GSD-1 (21-499 kW), GSLD-1 (500-1999 kW), and GSLD-2 (above 2000 kW). As ordered by the Commission, each of these rate classes has the same demand charge while the energy charges vary inversely with the rate class's kW threshold.

Q. How have customers reacted to this rate structure?

A. In certain cases, customers have attempted to circumvent the rate structure by artificially inflating or "spiking" their kW demand so as to qualify for the lower energy charges associated with the GSLD-1 rate class. (See Document No. RM-15, Docket No. 030623-EI, Hearing November 4, 2004, Witness George Brown, transcript pages 194-199). Other customers have merely complained that "the 500 kW demand level does not have any 'magic' that reduces FP&L costs of providing service." (Direct Testimony of Sheree L. Brown on behalf on Publix Super Markets, Inc, Docket No. 001148-EI).

Q. What does the cost of service study show in terms of the cost of serving customers below the 500 kW threshold and those above it, in other words those in the GSD-1 and GSLD-1 rate class?

A. As shown in the figures below, the energy unit costs are nearly identical for both classes while the demand unit cost is considerably higher for the GSLD-1.

Rate Class	GSD-1	GSLD-1	difference
Energy Unit Costs, cents/kWh (1)	.504	.503	0%
Demand Unit Costs, $/Billing kW (2)	8.96	11.15	24%

Sources:

(1) Energy revenue requirements from MFR E-6b divided by kWh sales

(2) Demand revenue requirements from MFR E-6b, divided by billing kW without the 10kW exemption

In addition, as I discuss later in my testimony, production and transmission demand costs are more appropriately recovered on an energy basis than through billing kW. Thus, the proposed unit costs for rate design are as follows:

Rate Class	GSD-1	GSLD-1	difference
Energy Unit Costs, cents/kWh (1)	2.09	1.97	-6%
Demand Unit Costs, $/Billing kW (2)	3.40	4.30	26%

Sources:

(1) Energy revenue requirements plus production and transmission demand revenue requirements from MFR E-6b divided by kWh sales

(2) Distribution demand revenue requirements from MFR E-6b, divided by billing kW without the 10 kW exemption

Q. What did you conclude from this?

A. I conclude that there is no basis for the assumption that the cost to serve customers automatically reduces when a customer moves from 499 kW to 500 kW. Indeed, *whether one follows my suggested unit cost calculation or the method advocated by Mr. Selecky, the cost of GSLD-1 is, if anything, higher than the cost of serving GSD-1 customers.* In short, the current rate structure which artificially reduces a customer's bill upon reaching 500 kW is flawed.

Q. How should this problem be addressed?

A. One option would be to increase both the GSD-1 and GSLD-1 rate classes to their full cost of service. However, this proposal would likely result in GSLD-1 customers paying *more* than GSD-1 customers. As a compromise, it is reasonable to evaluate whether the demand and energy charges for GSD-1 and GSLD-1 should be made equal. There are numerous cases where existing rate classes have been combined for ratemaking purposes (Docket No. 910890-EI, Order No. PSC-92-1197-FOF-EI; Docket No. 810002-EU, Order No. 10306). The Commission offers guidance on evaluating whether rate classes should be collapsed for ratemaking purposes. Specifically, the Commission has used the ratio of load factor to coincidence factors to evaluate whether rate classes should be combined

(Docket No. 820150-EU, Order No. 11498). The ratio of load factor to coincidence factor for the GSD-1 and GSLD-1 classes is as follows:

GSD-1: 76%

GSLD-1: 81%

Thus, the rate classes' ratios of load factor to coincidence factor are comparable. This suggests that the load characteristics of the rate classes are reasonably close and the use of a single set of demand and energy charges is appropriate.

Q. **Does FPL propose applying the single set of demand and energy charges to other rate classes?**

A. The Company proposes to include GSLD-2 in the combined rate treatment since its unit costs are comparable to those of GSLD-1. The corresponding curtailable (CS) rate classes would also be included in this proposal since the only difference between the otherwise applicable GSLD rates and the CS rate classes is the curtailable credit. At the same time, separate customer charges would be set for each rate class.

Q. **How have the intervenors reacted to this proposal?**

A. As previously referenced, Mr. Selecky on behalf of the Commercial Group suggests that there is no basis for combining the GSD-1, GSLD-1, GSLD-2, CS-1, and CS-2 rate classes. The above analysis, however, supports the Company's proposal. Mr. Selecky also implies that the revenue increases for GSLD-1 and GSLD-2 are somehow inflated because of the Company's proposal to have a single set of demand and energy charges for GSD-1, GSLD-1 and GSLD-2. The opposite is true. While the Company would prefer to move all rate classes to within +/- 10% of parity, the parity targets for the GSLD-1 and GSLD-2 were reduced from 90% to 80% and 82% respectively in order to: 1) achieve a standard set of demand and energy charges; and 2) to account for the revenue loss associated with the Optional High Load Factor rate the Company is offering.

Q. **Did Mr. Selecky raise any other issues regarding the GSD-1, GSLD-1, and GSLD-2 rate classes?**

A. Yes. Mr. Selecky disagrees with the specific energy and demand charges proposed for GSD-1, GSLD-1, and GSLD-2 rate classes (Direct Testimony, page 25). Under the Company's proposal the demand charge would recover all distribution demand-related costs and a portion of production and transmission demand-related costs while the energy charges would recover the remaining portion of demand-related production and transmission costs as well as all energy-related costs. Mr. Selecky, on the other hand, opposes the recovery of any production or transmission demand-related costs through the energy charges.

Q. **Why is the Company proposing to recover a portion of its demand-related production and transmission costs through the energy charge?**

A. The decision on which billing determinant should be used to recover a particular cost should be based on an evaluation of which billing determinant best tracks those costs. In the case of demand-related production and transmission costs the costs are allocated on the basis of 12 CP contributions. Thus, to the maximum extent possible, the billing determinant used to recover production and transmission demand-related costs should track a customer's 12 CP contributions. Since customers are not billed on the basis of their 12 CP contributions, this becomes a question of whether kWh sales or billing kW better mirrors a customer's 12 CP contribution.

The data clearly show that kWh sales more closely track customers' 12 CP contributions than billing kW does. Over time, increases in billing kW within the GSLD-1 rate class have fallen short of increases in either kWh sales or 12 CP contributions.

Cumulative Increases (1984-2006) - GSLD-1

kWh Sales	153%
Billing kW	117 %
12 CP	162%

In addition, a statistical analysis shows that the correlation between kWh sales and 12 CP contribution is greater than that between billing kW and 12 CP contributions.

Correlation Coefficient with 12 CP - GSLD-1 Sample Points

kWh Sales (1) 97%

Billing kW (2) 93%

Notes (1) – annual kWh sales

Notes (2) – maximum monthly kW demands

Q. Is the use of a correlation analysis a common technique for determining how demand-related production and transmission costs should be recovered?

A. Yes, it has been used in a number of Commission decisions, including Docket No. 830470-EI, Order No. 13771 and Docket No. 840086-EI, Order No. 14030.

Q. Are the results of the correlation analysis consistent with past experience?

A. Yes. The Commission has long recognized that there is an inherent mismatch between billing kW and the 12 CP demands which are used to allocate production and transmission demand costs. In Docket 930759-EG, Order No. PSC-93-1845-FOF-EG, the Commission determined that it was not appropriate for FPL to recover demand-related costs on a billing kW basis because of the mismatch between billing demand and coincident peak demand. The Commission specifically recognized that "for billing purposes, an individual customer's maximum demand (billed kw) is determined by the customer's greatest amount of continuous use during any 30 minute time period. The customer's billed kW may or may not occur when the system is at its peak."

The Commission has also recognized this "mismatch" in approving the rates for other utilities. In Docket No. 830470-EI, Order No. 13771, pages 46-47, the Commission concluded that "increasing the proportion of demand-related costs recovered through demand charges is inequitable to low load factor customers when KWH's are as highly or even more correlated with coincident demand than billing demand and when there is a wide variation of coincidence factors within a class." Thus, the Commission has approved recovering costs allocated on a 12 CP basis on a kWh energy basis.

Q. Does Mr. Selecky perform any statistical study indicating that billing kW tracks 12 CP demands better than kWh sales does?

A. No.

Q. Then what basis does Mr. Selecky offer for opposing the recovering costs allocated on the basis on 12 CP on the basis of kWh sales?

A. Mr. Selecky claims that all demand-related costs, including those allocated on the basis of 12 CP, should be recovered through the demand charges in order to send the right price signal to customers (Direct Testimony, page 25). Yet, Mr. Selecky does not explain why the recovery of 12 CP costs through the demand charge sends an appropriate price signal when kWh sales clearly does a superior job of tracking these costs.

CILC RATES

Q. Please discuss the testimony of Federal Executive Agencies witness Goins relating to the CILC rate schedules.

A. In his direct testimony, Dr. Goins proposes an adjustment to exclude the "energy-related gas turbine production costs included in FPL's proposed energy charge" for the CILC-1G; CILC-1D; and CILC-1T rate schedules (Direct Testimony, page 17, lines 18 – 21).

Q. What do you conclude as a result of your review of Dr. Goins' proposed adjustment?

A. The Commission should reject Dr. Goins' proposed adjustment to the CILC energy charges for the following reasons:

- It is inconsistent with the cost of service methodology proposed by FPL and supported by Commission precedent;
- It is inconsistent with FPL's resource plan;
- It would be costly and impractical to implement;
- It has not been calculated correctly.

Q. Why is Dr. Goins' proposed adjustment to the CILC energy charges inconsistent with the cost of service methodology proposed by FPL and supported by Commission precedent?

A. As I have previously discussed, the Commission, in evaluating the appropriate method of allocating production plant, has recognized that a portion of these costs should be allocated on the basis of kWh. Consistent with Commission precedent, FPL is proposing a 12 CP and 1/13th methodology which classifies approximately 8% of production plant as energy-related. The adjustment proposed by Dr. Goins is clearly at odds with the 12 CP and 1/13th methodology because under his proposal CILC rates would not recover their share of gas turbines classified as energy-related.

Q. What basis does Dr. Goins offer for proposing rates which do not follow the 12 CP and 1/13th methodology?

A. The basis for the adjustment as proposed by Dr. Goins is described as follows:

> FPL's CILC interruptible service option is primarily used to reduce peaking (that is, gas turbine) capacity requirements. Requiring CILC customers to pay energy-related nonfuel gas turbine production costs is inconsistent with excluding demand-related gas turbine production costs form the CILC Load Control On-Peak demand charges. (Direct Testimony, page 17, lines 11 – 14)

Q. Do you find Dr. Goins' argument compelling?

A. No, I do not. Implementing Dr. Goins proposed adjustment to the energy charges for the CILC rate schedules, is inconsistent with the cost of service methodology proposed by FPL and supported by Commission precedent. As I observed in my direct testimony, "all generating units under the 12 CP and 1/13th methodology are treated consistently." (page 17, lines 4-5). Dr. Goins' proposed adjustment would isolate the cost of one type of generating unit, gas turbines, and exempt certain rate classes from the cost of those units appropriately allocated to them on the basis of the 12 CP and 1/13th methodology.

Q. Is Dr. Goins' proposed adjustment to the energy charge for the CILC rate schedules inconsistent with Dr. Goins' own conclusions regarding the 12 CP & 1/13th methodology?

A. Yes. His proposed adjustment is particularly surprising given his recognition of the "Commission's past support" (Direct Testimony, page 6, lines 6 – 7), and his own assessment and conclusion regarding FPL's filed cost of service study. In numerous points in his testimony Dr. Goins assesses FPL's cost of service study as "reasonable." (Direct Testimony, page 7, line 25 through page 8, line 2, page 9, lines 19 – 21, page 9, line 26 through page 10, line 2).

Q. What impact does exempting certain rate classes from the costs appropriately allocated to them on the basis of the 12CP and 1/13th methodology have?

A. Dr. Goins appropriately observes that, if a "cost-of-service methodology does not allocate and assign cost responsibility in a reasonable manner, then interclass revenue subsidies are created and specific class rates are either over- or under-priced." (Direct Testimony, page 7, lines 20 – 23). Unfortunately, such interclass subsides are certain to result from Dr. Goins' proposed CILC energy adjustment. Dr. Goins calculates a maximum revenue impact of approximately $2 million from his proposal, but he makes no recommendations as to how this revenue shortfall is to be recovered. The effect of Dr. Goins' failure to address the recovery of the $2 million revenue impact of his proposed adjustment raises the near-certainty that "interclass revenue subsidies are created and specific class rates are either over- or under-priced."

Q. Why is Dr. Goins' proposed adjustment inconsistent with FPL's resource plan?

A. From an FPL resource planning perspective the net kWh energy reduction from the CILC program is negligible. This is because FPL's resource plan makes the following assumptions: 1) the number of CILC load control events is limited, 2) load control events typically call on only a portion of CILC's interruptible load, and 3) the majority of any unserved energy resulting from a load control event will be served later. Thus, implementing an adjustment to the energy charge for the CILC rate schedules on the basis of their non-firm peak load characteristics is inconsistent with FPL's resource plan. Dr. Green's testimony also addresses this point.

Q. Why is Dr. Goins' proposed adjustment costly and impractical to implement?

A. Dr. Goins' proposed adjustment requires that the energy charge for the CILC rate schedules distinguish between firm and non-firm usage based on an assumed load factor and the level of controllable versus firm demand contractually specified by the CILC customers in their agreement for CILC service. (Direct Testimony, page 18, lines 4 – 11) Dr. Goins ignores the significant revision to the billing system that would be necessary for these CILC rate schedules in order to implement his proposed adjustment. The existing billing system for these CILC rate schedules has no capability to distinguish firm versus non-firm energy usage and apply separate energy charges to each. This revision is also significant because the implementation of Dr. Goins' methodology requires an assumption concerning load factor and the customers' contractual designation of controllable versus firm load which must also be reflected in the billing system for these CILC rate schedules. While I have not determined a specific estimate, my experience in implementing other rate revisions suggests that significant time and resources would be required. Given the commitment of resources required to implement the revised rates FPL is proposing in this docket, implementing the change Dr. Goins is proposing in 2006 as well would be extremely difficult. The time and resources required to make the billing changes Dr. Goins is proposing should also be evaluated in light of the fact that the CILC rate schedules have been closed to new customers for a number of years.

Q. Please describe the calculation of Dr. Goins' proposed adjustment.

A. As described by Dr. Goins, this adjustment is implemented by excluding the cost of "gas turbine production capacity" expressed on a cents/kWh basis from the energy charge for the CILC rate schedules. Dr. Goins specifies "gas turbine production capacity" in numerous references in his testimony (Direct Testimony, page 17, lines 10-14 and lines 18-21).

Q. Was Dr. Goins' proposed adjustment calculated correctly?

A. No.

Q. What problem did you find with the calculation of Dr. Goins' proposed adjustment?

A. Dr. Goins intended to base his adjustment to the CILC energy charge on the cost of gas turbine production but instead used the costs for both gas turbines and combined cycle production units. As shown in the cost of service study filed in this docket, there are three production cost categories: Steam; Nuclear; and Other. These three categories are shown in MFR E-1, E-3a and E-4a. Additional detail on the composition of "Other Production" plant was provided in MFR B-8. MFR B-8 shows that the Other Production cost category includes the cost of gas turbines at Ft. Myers, Ft. Lauderdale, and Port Everglades. That category, however, also includes the combined cycle units at Ft. Myers, Manatee, Martin, Putnam, and Sanford power plants. MFR B-8 shows that less than 10% of the Total Other Production cost category is attributable to gas turbine units. Combined cycle units, which clearly represent the bulk of FPL's Other Production resources, were not intended to be included in Dr. Goins' proposed adjustment and, indeed, given their substantially different operating characteristics during periods other than the system peak, should not be included in any such adjustment. Thus, Dr. Goins calculations drastically overstate the impact from excluding the energy-related portion of gas turbines because he excludes both gas turbines and combined cycle units in his calculation.

Q. Why did Dr. Goins assume that the Other Production cost category consisted strictly of gas turbines?

A. In MFR E-6 a row heading which should have read "combined cycle and gas turbines" was inadvertently truncated as "gas turbines." While I regret any confusion this may have caused, it in no way altered the results of the cost of service study because the treatment of both gas turbines and combined cycle units is identical under FPL's proposed cost of service methodology. Given that there is no reason in that methodology for isolating the cost of gas turbines for a unique cost treatment, there was no way to predict that MFR E-6 would have been interpreted and used in the manner that Dr. Goins has interpreted it.

Q. What impact did excluding the cost of combined cycle units have on Dr. Goins' proposed CILC energy charges?

A. As I mentioned earlier, gas turbine units account for approximately less than 10% of Other Production plant in service. Thus, an adjustment designed to reflect the exclusion of gas turbine units would be only a small fraction of the amount Dr. Goins calculates.

Q. Please summarize your conclusions regarding the testimony of Dr. Goins.

A. My review of Dr. Goins' testimony has highlighted numerous inconsistencies and has shown how the proposed adjustment to the energy charge for the CILC rate classes has not been calculated correctly. Dr. Goins proposed adjustment should be rejected.

HIGH LOAD FACTOR TIME-OF-USE (HLFT) RATE

Q. Please address Mr. Selecky's comment on page 26 of his testimony that a high load factor customer will generally be cheaper to serve than a customer with a lower load factor.

A. Higher load factor customers may or may not be cheaper to serve than other customers depending on the type of cost in question. If we are looking at costs driven by localized peaks, such as distribution costs, then yes, high load factor customers are less expensive to serve on a per kWh basis. On the other hand, if we are considering costs driven by the system peak, then the cost of serving a customer depends on *timing* of their load. Many lower load factor customers contribute less to the system peak than do higher load factor customers by virtue of the fact that they are simply using electricity in fewer hours and therefore may not have substantial usage at the time of the system peak. In fact, a positive relationship between load factor and coincidence factor has long been recognized in ratemaking. In other words, higher load factor customers are more likely to be consuming at the time of the system peak than are lower load factor customers.

Q. How does the relationship between load factor and coincidence factor support FPL's proposed HLFT rate?

A. While there is the positive relationship between load factor and coincident factor, above a certain threshold increases in load factor are likely to be associated with progressively smaller increases in a customer's coincident factor. As illustrated in Document No. RM-16, this threshold occurs around a load factor of 70%. In addition, because the timing of a customer's load is critical, it is important that the HLFT rate encourage customers to maintain or increase their load factor only to the extent that kWh are added during the off-peak period. This is why the on-peak energy charge under the HLFT rate is significantly higher than the off-peak energy charge.

Q. On page 27 of his direct testimony, Mr. Selecky asserts that FPL's choice of a 70% load factor break-even calculation was <u>arbitrary</u>. Do you agree?

A. No. As described above, the decision to use a 70% load factor to calculate the break-even point was based on the load characteristics of the eligible rate classes. By contrast, the 65% load factor break-even calculation advocated by Mr. Selecky represents the average load factor for the rate class. Rather than recognizing higher than normal load factor usage, Mr. Selecky's proposed rate would reward customers with nearly average load factors.

Q. Has the Commission previously approved optional rates based on load factor?

A. Yes. There are numerous examples (Docket No. 74437-EU, Order No. 6650; Docket No. 920821-EM, Order No. PSC-92-1006-FOF-EM; Docket No. 020883-EC, Order No. PSC-02-1630-TRF-EC). In past cases, rates based on a threshold load factor of 70-75% have also been approved.

Q. Do you agree with Mr. Selecky's assertion that FPL's choice of a 70% load factor break-even calculation was <u>limiting</u>?

A. No. MFR E-13c shows 28% of the kWh sales from the eligible rate classes will qualify for the HLFT rate. In total, customers qualifying for and saving under the HLFT rate will represent 9.9 billion kWh. By any measure, this is far from limiting.

Q. What is the revenue impact of providing a high load factor rate with a 70% break-even point?

A. Use of a 70% break-even point results in total annual customer savings of approximately $17 million. Again, this is not the revenue impact one would associate with an offering of "limited" applicability.

Q. How would this revenue impact be altered by Mr. Selecky's proposed 65% load factor break-even point?

A. Use of a 65% break-even point would increase the revenue loss associated with the HLFT rate by almost 60%, to $27 million.

Q. Does Mr. Selecky suggest which customers should offset this additional revenue loss?

A. No.

Q. How would the added revenue loss – approximately $10 million – be recovered?

A. Clearly, the rates paid by other customers would have to increase to offset this revenue loss.

TURKEY POINT UNIT 5 ADJUSTMENT

Q. Please summarize your direct testimony with regard to the Turkey Point Unit 5 adjustment.

A. Consistent with the treatment of production plant in the 2006 test year I have allocated the plant cost of the Turkey Point Unit 5 on the basis of 12 CP and 1/13th and proposed an adjustment to the energy charges of each rate schedule to recover these costs.

Q. Have the intervenors addressed the proposed rate adjustments for Turkey Point Unit 5?

A. Yes. Mr. Baron (Direct Testimony, page 52, lines 4-11) and Mr. Selecky (Direct Testimony, page 29, lines 3-8) oppose the recovery of Turkey Point Unit 5 through kWh energy charges. However, as I have already demonstrated, kWh sales do a better job of tracking 12 CP than does billing kW. The vast majority of Turkey Point Unit 5 costs are allocated on the basis of 12 CP. Accordingly, the recovery of Turkey Point Unit 5 costs through the kWh energy charges is appropriate.

OVERVIEW OF COMMERCIAL RATES

Q. Are there any other issues regarding the Company's proposed rates you would like to address?

A. Yes. Mr. Selecky claims that electric rates are a significant measure of performance and that, by this measure, the Company's performance is not superior (Direct Testimony, page 5, lines 20-33). In support of this contention, Mr. Selecky manipulates data from the Edison Electric Institute (EEI) Typical Bills and Average Rates Reports for Summer 2004 (Summer Survey) and Winter 2005 (Winter Survey) to allegedly demonstrate that the Company's electric rates are in the top quartile of its peers.

Q. Do you believe Mr. Selecky's analysis is valid?

A. No. First of all, Mr. Selecky's analysis is based on total bill calculations which include fuel, clauses and taxes, items which are not at issue in this proceeding. In addition, Mr. Selecky limits his comparisons to electric utilities in the South, a region which according to EEI possesses among the lowest electric rates in the country. To further skew the analysis, Mr. Selecky does not simply average the results of the Summer Survey and Winter Survey but instead disproportionately weights the Winter Survey results.

Q. Please explain.

A. EEI reports a typical FPL 1,000 kWh residential bill of $86.43 and $89.92 for the Summer and Winter Surveys respectively. The arithmetic average of these two figures is $88.18 or 8.82 cents per kWh. Mr. Selecky, however, uses a figure of 8.88 cents for FPL. This figure appears to be the result of a seasonal weighting that places a 67% weight on the Winter Survey and a 33% weighting on the Summer Survey. Because FPL's sales during the summer months substantially exceed its winter sales, an argument could be made that if any weighting of the results is to be done, the heavier weight should be placed on the results of the Summer Survey. The only rationale for placing undue emphasis on the Winter Survey appears to be an effort to deflate the figures for other utilities, such as Progress North Carolina, which offer lower seasonal rates in the winter.

Q. What information can be drawn from the EEI reports in terms of the Company's rates versus those of other electric utilities?

A. Bear in mind that total bill comparisons, such as those reported by EEI, include fuel and other clauses which are not at issue in this proceeding. Nevertheless, the Company's residential rates are comparable to national averages based on the EEI reports. As shown in Document No. RM-17, the typical bills reported in the Summer Survey and the Winter Survey are, on average, less than the national typical bills reported for the same period. In light of the fact that almost 90% of the Company's customer base is residential, this is the most significant bill comparison that can be drawn from the EEI reports.

Q. What about the rates for commercial and industrial customers?

A. Following the same procedure of averaging the Winter Survey and Summer Survey results, the Company's typical commercial bills are comparable to the national averages while typical industrial bills are slightly higher.

Q. Does this mean that FPL's industrial customers are paying more on average than customers nationally while commercial customers are paying about the same as customers nationally?

A. I think it would be premature to draw that conclusion based strictly on the typical bill surveys. Because of the diversity of rate options available to them, typical bill comparisons are not as meaningful for commercial and industrial customers as they are for residential customers. For example, 20 out of FPL's 30 rate schedules are designed for commercial and industrial customers. The typical bill calculations reported for FPL in the EEI reports, however, are based strictly on standard general service demand rates. Customers taking advantage of time-of-use, curtailable service, and load control options would pay lower rates. In fact, a substantial percentage of FPL's eligible customers are doing just that. For example, 37% of commercial customers with demands of 500 kW or higher are on rate options not incorporated into the EEI typical bill calculations. The percentage of industrial customers with demands of 1,000 kW or higher is even more dramatic with 83% of those on rate options not incorporated into the EEI survey.

Q. What impact would these rate options have on the typical bill calculations of commercial and industrial customers?

A. As shown in Document No. RM-17, I have recalculated the typical bills reported for FPL using one of the rate options commercial and industrial customers are taking service under, CILC-1D. Based on the CILC-1D rate, FPL's typical bills for both commercial and industrial are lower than the national averages.

Q. CILC is sometimes viewed as an option limited to industrial customers. Do any commercial customers take service on CILC?

A. Absolutely. In fact, three quarters of FPL's CILC customers are commercial.

Q. Has anyone raised the rate options available to commercial customers as an issue in this case?

A. Yes. Ms. Civic and Mr. Galura in panel testimony for the Commercial Group claim that there have been few rate schedules tailored to the needs of their facilities.

Q. Is this assessment accurate?

A. No. The only way that their testimony would be accurate is if one focused exclusively on rate schedules tailored to the specific needs of the Commercial Group as a special discount which is available only to their members. On the other hand, however, if one defines a rate schedule "tailored to their needs" as an optional rate which similarly situated customers may elect, then FPL offers several rate schedules tailored to the needs of customers in the retail sector. Customers operating in the retail sector are taking service under a variety of FPL's rate options, including time-of-use, CILC, the Commercial/Industrial Demand Reduction (CDR)

Rider, and curtailable service. Moreover, the optional HLFT rate proposed by FPL will provide savings for a substantial number of customers in the retail sector, including those in the Commercial Group.

Q. **Will all of the facilities represented by the Commercial Group qualify for the optional HLFT rate?**

A. No. The facilities represented by the Commercial Group are not a homogeneous group, at least in terms of their load characteristics. Nonetheless, three of out four of the Commercial Group's members will have qualifying facilities. In fact, it appears that in some cases the vast majority of the customer's facilities will qualify based on the 70% load factor proposed by the Company. The facilities associated with the fourth customer within the Commercial Group have substantially lower load factors and will not qualify for the HLFT rate - nor would they qualify even based on the 65% load factor breakeven proposed by the Commercial Group. Given the lack of homogeneity within the Commercial Group's facilities it appears that designing a rate "tailored to the needs" of every facility they represent is not possible.

CONCLUSION

Q. **Please summarize your rebuttal testimony.**

A. The intervenors representing larger C/I customers have filed testimony proposing to allocate costs away from the customers they are representing and onto the residential and smaller commercial customers. The price tag for their proposals is high. Consider, for example, just two of the recommendations of the Commercial Group, the use of the 150% rule-of-thumb and a 65% load factor threshold for the HLFT rate. In combination, these two proposals alone would allocate an additional $28 million to smaller customers. The use of cost of service methodologies not supported by Commission precedent, but advocated by intervenors in this case, would surely add to this figure. The Commission should reject the proposals by intervenors to alter the cost of service methodologies and rate design as proposed by FPL.

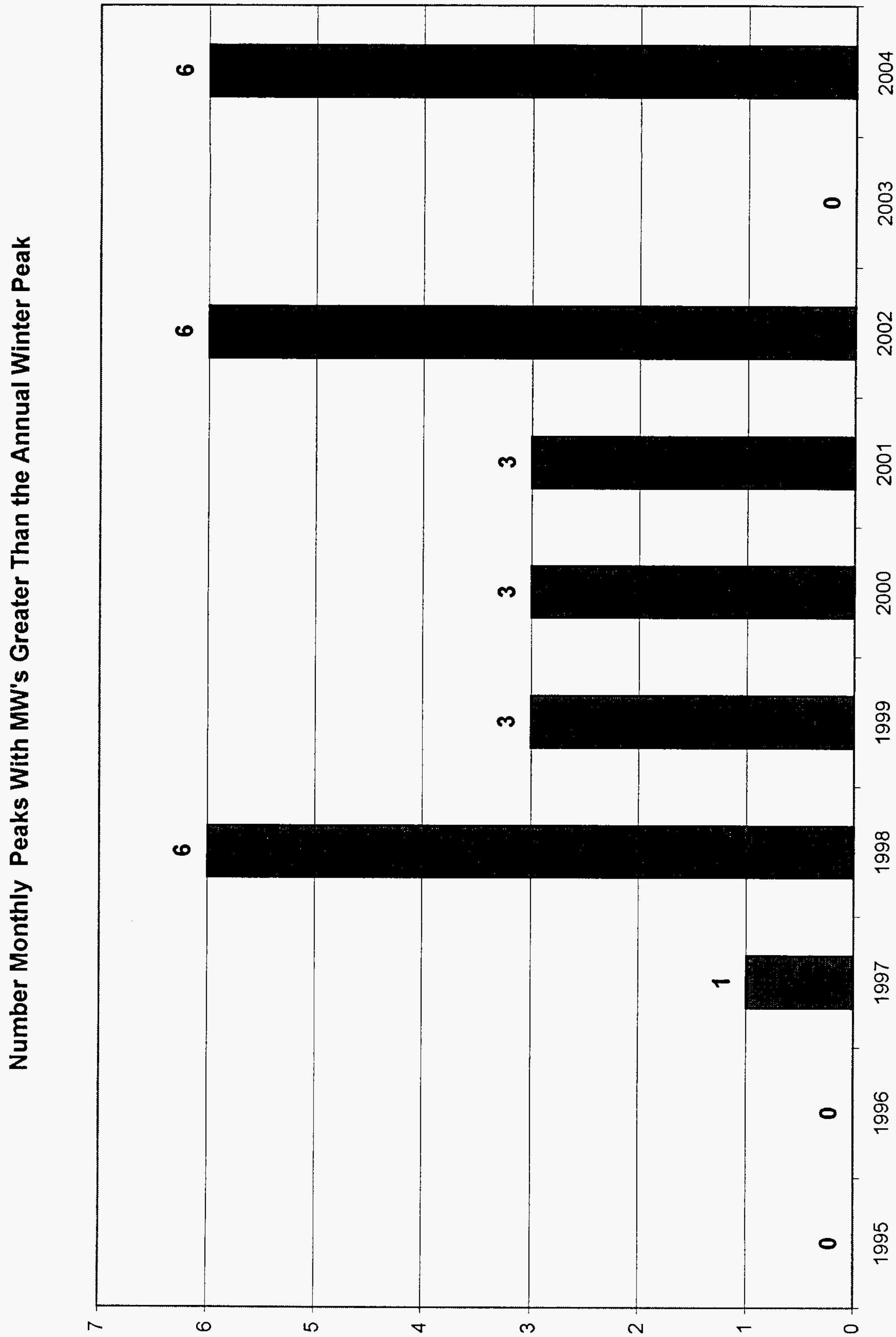
Q. Does this conclude your testimony?

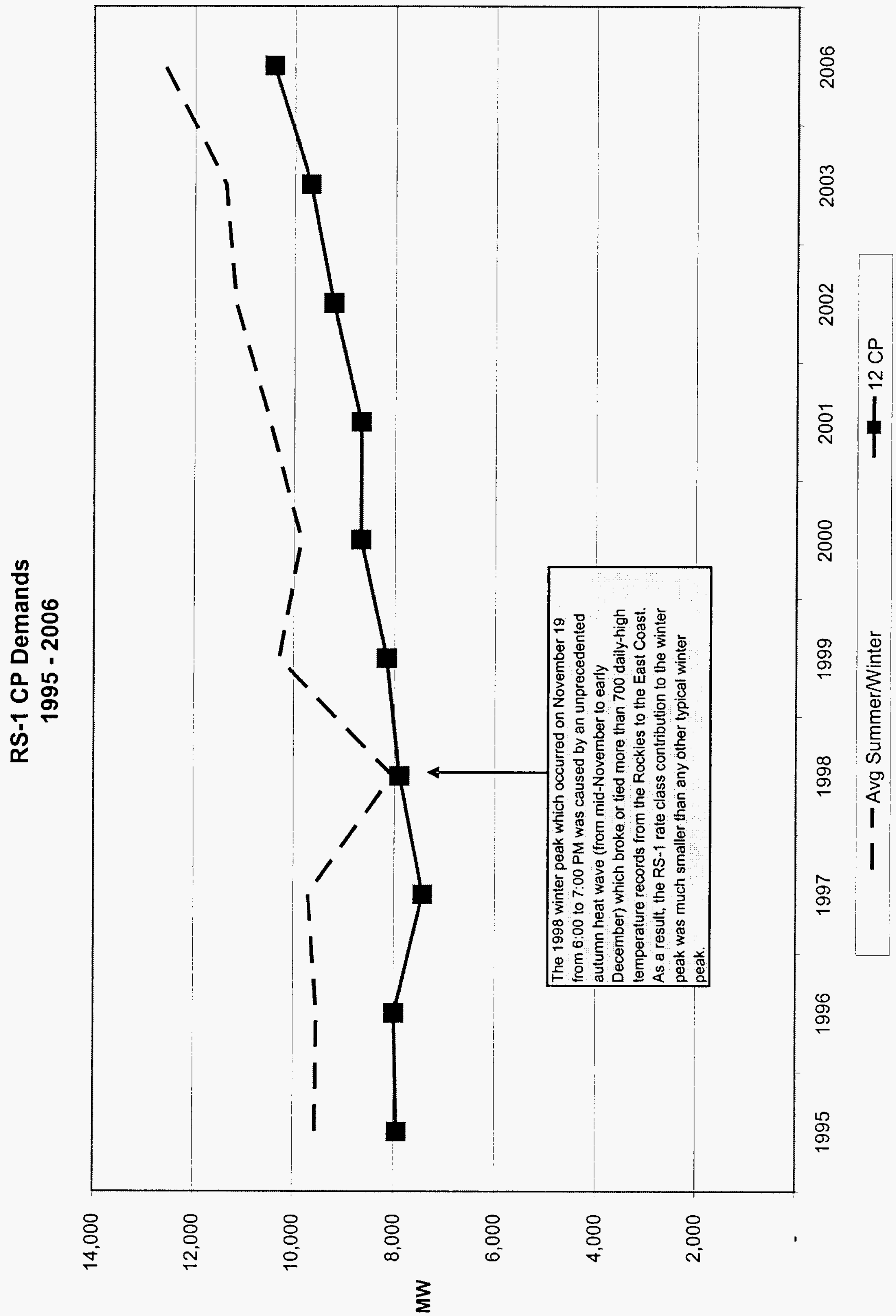
A. Yes

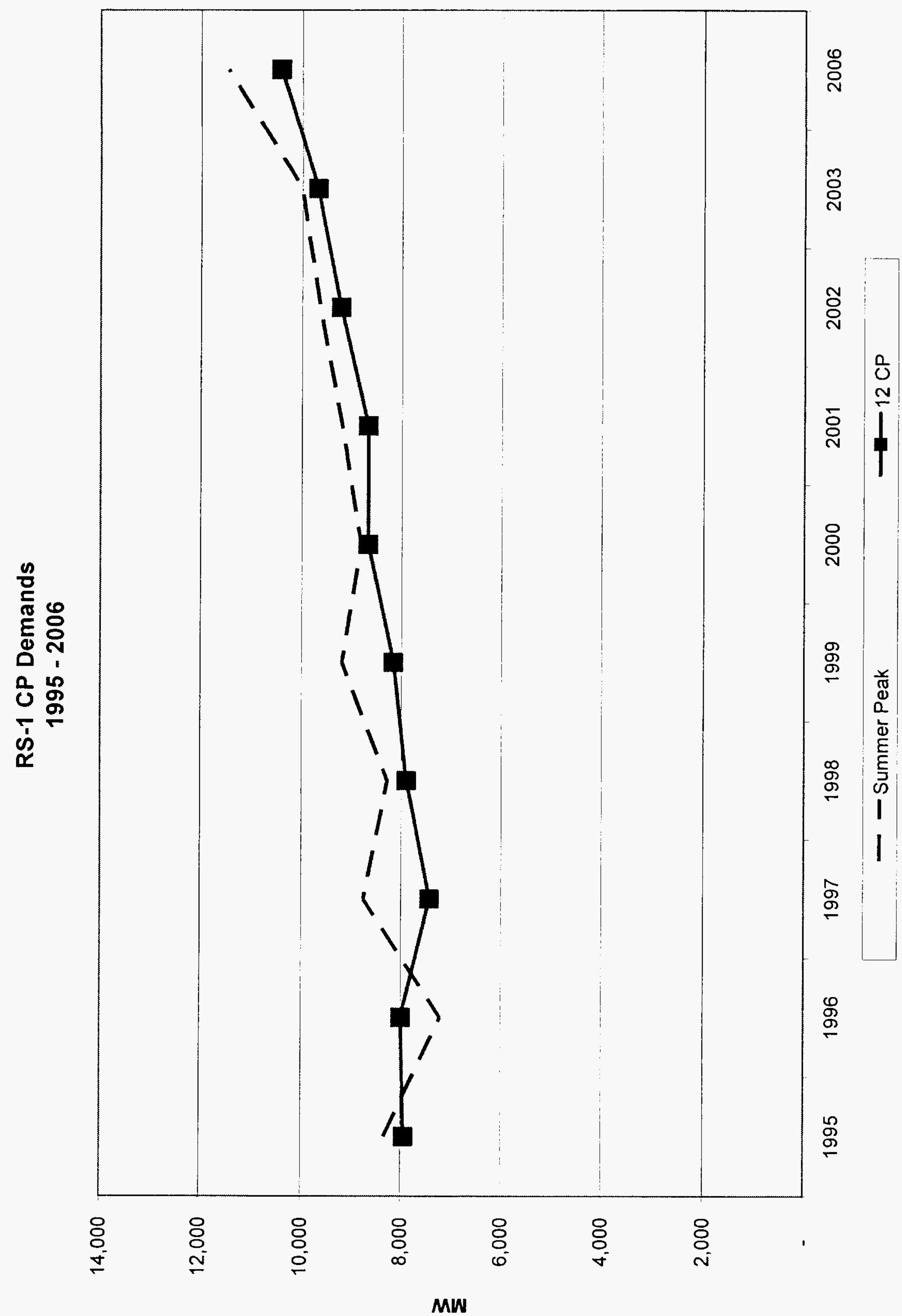
Florida Power & Light Company
Allocation of 2006 Projected Production Plant
Using Alternative Methodologies

	12CP		Summer Peak		Avg Summer/Winter Peak		12CP & 1/13th		Summer Peak & 1/13th		Avg Summer/Winter & 1/13th	
	Factor	Allocation	Factor	Allocation	Factor	Allocation	Factor	Allocation	Factor	Allocation	Factor	Allocation
CILC-1D	2.166%	230,223,746	1.927%	204,785,789	1.803%	191,656,925	2.219%	235,826,514	1.998%	212,345,323	1.884%	200,226,371
CILC-1G	0.167%	17,786,360	0.148%	15,683,011	0.142%	15,088,854	0.171%	18,190,155	0.153%	16,248,602	0.148%	15,700,149
CILC-1T	0.943%	100,240,829	0.828%	88,038,614	0.868%	92,280,091	0.973%	103,426,277	0.867%	92,162,694	0.904%	96,077,904
CS1	0.190%	20,224,558	0.195%	20,711,156	0.172%	18,232,536	0.194%	20,645,491	0.198%	21,094,658	0.177%	18,806,702
CS2	0.090%	9,580,534	0.084%	8,924,372	0.081%	8,603,286	0.092%	9,783,925	0.086%	9,178,236	0.084%	8,881,850
GS1	5.957%	633,110,105	6.559%	697,083,775	5.020%	533,546,312	5.950%	632,320,189	6.505%	691,372,807	5.085%	540,415,148
GSD1	20.401%	2,168,141,450	20.623%	2,191,786,358	17.693%	1,880,395,792	20.544%	2,183,366,570	20.749%	2,205,192,639	18.045%	1,917,755,194
GSLD1	8.528%	906,307,960	8.275%	879,421,180	7.342%	780,343,062	8.644%	918,661,050	8.410%	893,842,483	7.550%	802,385,759
GSLD2	1.254%	133,310,129	1.239%	131,680,759	1.091%	115,952,772	1.278%	135,826,304	1.264%	134,322,271	1.127%	119,804,128
GSLD3	0.134%	14,206,308	0.108%	11,451,322	0.115%	12,210,752	0.136%	14,481,462	0.112%	11,938,399	0.119%	12,639,411
MET	0.097%	10,269,462	0.096%	10,226,058	0.095%	10,111,238	0.097%	10,257,120	0.096%	10,217,055	0.095%	10,111,067
OL-1	0.024%	2,596,525	0.000%	-	0.000%	-	0.031%	3,246,488	0.008%	849,695	0.008%	849,695
OS-2	0.017%	1,766,308	0.008%	881,126	0.008%	811,608	0.017%	1,779,298	0.009%	962,207	0.008%	898,037
RS1	59.811%	6,356,542,012	59.835%	6,359,184,835	65.493%	6,960,473,668	59.407%	6,313,679,038	59.430%	6,316,118,567	64.653%	6,871,154,413
SL-1	0.098%	10,464,182	0.000%	-	0.000%	-	0.122%	12,996,165	0.031%	3,336,920	0.031%	3,336,920
SL-2	0.045%	4,786,281	0.039%	4,167,863	0.040%	4,269,758	0.047%	4,947,757	0.041%	4,376,909	0.042%	4,470,966
SST-TST	0.071%	7,533,655	0.028%	3,007,083	0.030%	3,221,329	0.072%	7,631,821	0.032%	3,453,446	0.034%	3,651,212
SST1-DST	0.000%	-	0.000%	-	0.000%	-	0.000%	83	0.000%	83	0.000%	83
SST2-DST	0.002%	232,207	0.001%	124,450	0.002%	248,923	0.002%	238,496	0.001%	139,027	0.002%	253,926
SST3-DST	0.004%	475,389	0.006%	640,252	0.003%	351,095	0.005%	493,799	0.006%	645,981	0.004%	379,066
TOTAL	100.000%	10,627,798,001	100.000%	10,627,798,001	100.000%	10,627,798,001	100.000%	10,627,798,001	100.000%	10,627,798,001	100.000%	10,627,798,001

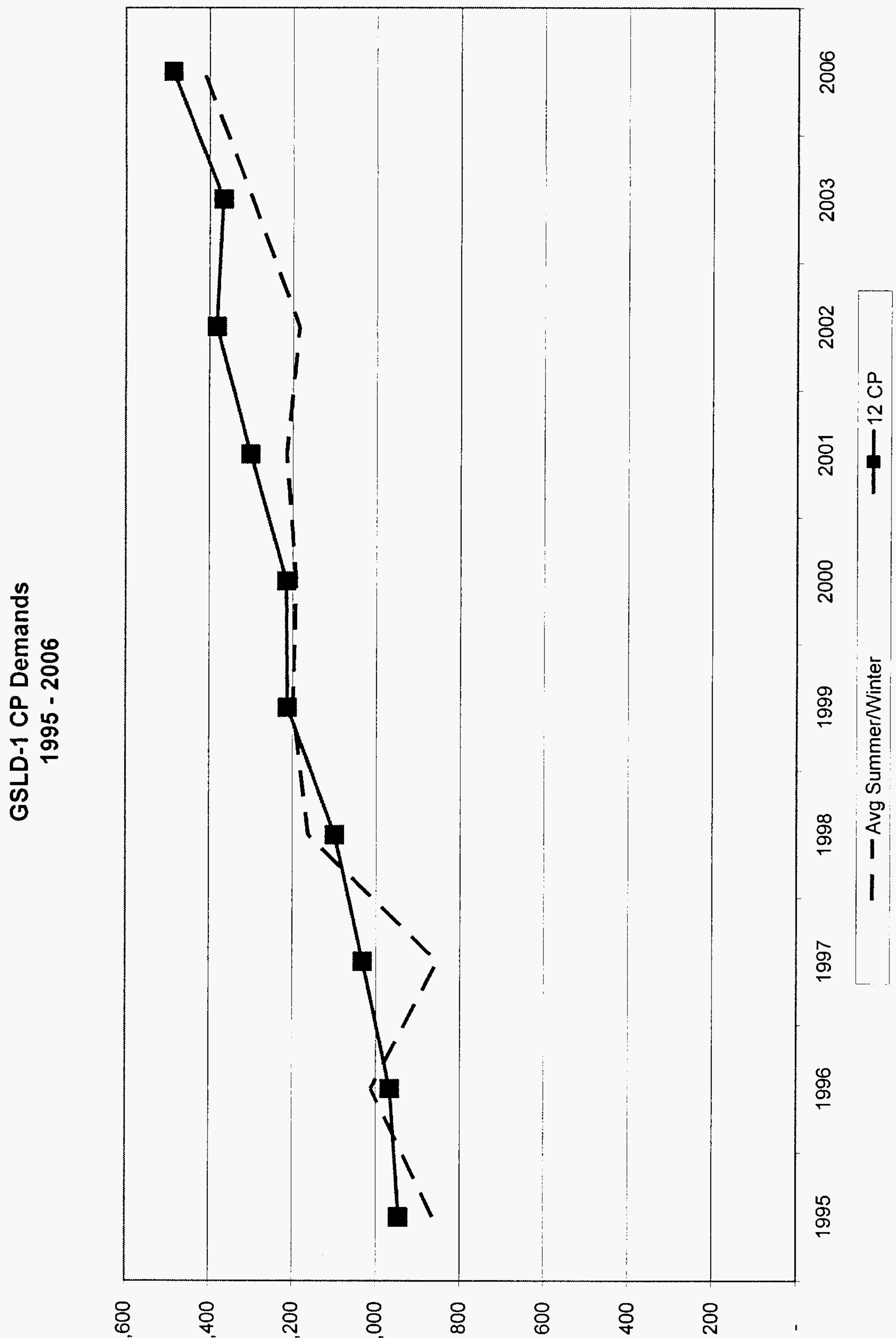
Docket Nos. 050045-EI and 050188-EI
R. Morley, Exhibit No. ___________
Document No. RM-12, Page 1 of 1
No of Monthly Peaks Greater than Winter Peak

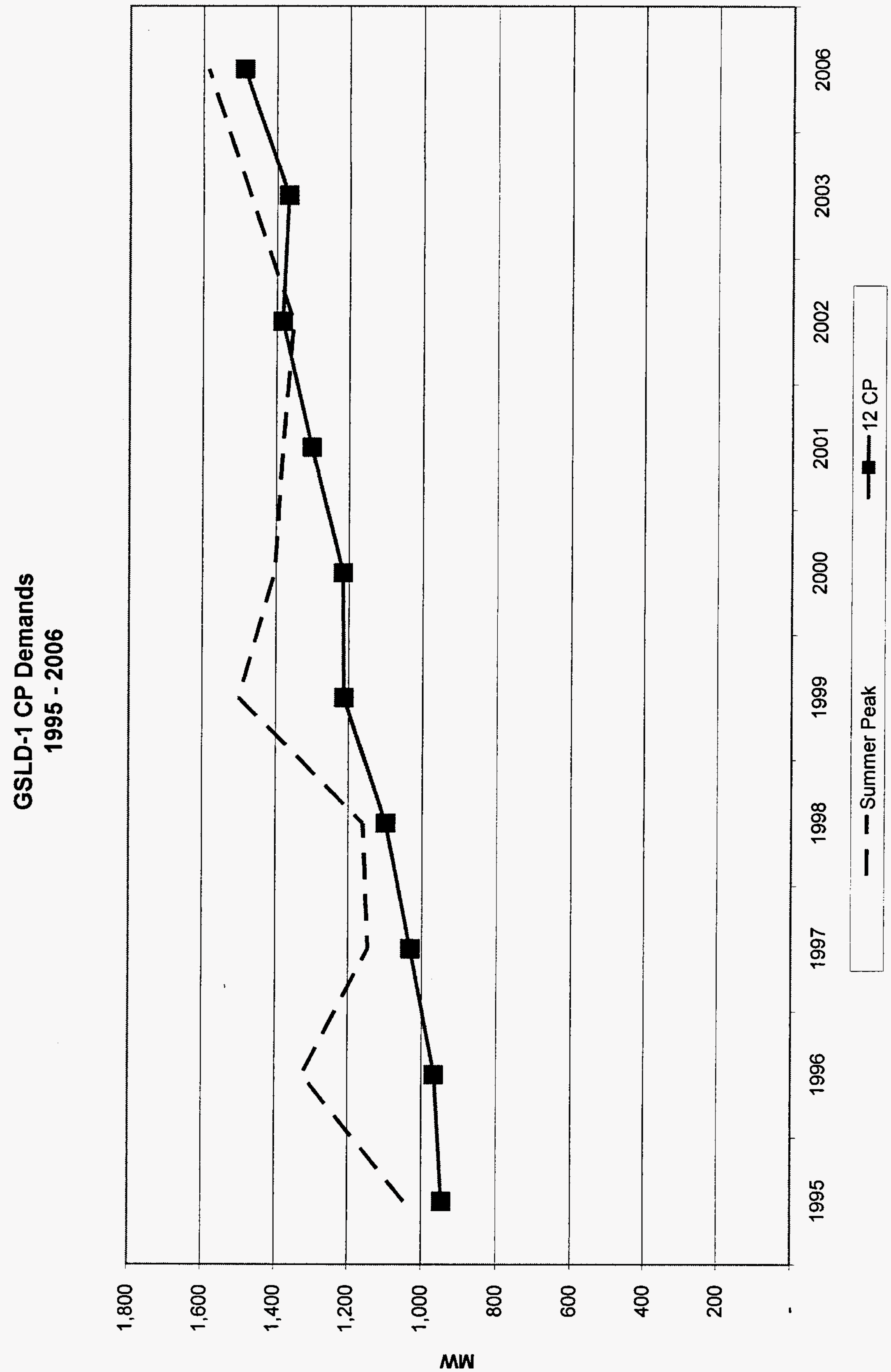



RS-1 CP Demands
1995 - 2006
MW
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
1995
1996
1997
1998
1999
2000
2001
2002
2003
2006
The 1998 winter peak which occurred on November 19 from 6:00 to 7:00 PM was caused by an unprecedented autumn heat wave (from mid-November to early December) which broke or tied more than 700 daily-high temperature records from the Rockies to the East Coast. As a result, the RS-1 rate class contribution to the winter peak was much smaller than any other typical winter peak.
Avg Summer/Winter
12 CP


RS-1 CP Demands
1995 - 2006
MW
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
1995
1996
1997
1998
1999
2000
2001
2002
2003
2006
Summer Peak
12 CP

Docket Nos. 050045-EI and 050188-EI
R. Morley Exhibit No. __
Document RM-13, Page 3 of 4
RS-1 and GSLD-1 CP Demands




GSLD-1 CP Demands
1995 - 2006
MW
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
1995
1996
1997
1998
1999
2000
2001
2002
2003
2006
Summer Peak
12 CP

Customer Density
(per square mile)

Company	No. of Customers per Square Mile
Choctawhatchee Electric Coop	10
Gulf Power Company	54
Progress Energy Florida	75
Florida Power & Light Company	149

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO 030623-EI

In the Matter of

COMPLAINTS BY OCEAN PROPERTIES, LTD., J.C. PENNEY CORP., TARGET STORES, INC., AND DILLARD'S DEPARTMENT STORES, INC. AGAINST FLORIDA POWER & LIGHT COMPANY CONCERNING THERMAL DEMAND METER ERROR.

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THE OFFICIAL TRANSCRIPT OF THE HEARING,
THE .PDF VERSION INCLUDES PREFILED TESTIMONY

VOLUME 1

Pages 1 through 216

PROCEEDINGS:	HEARING
BEFORE:	COMMISSIONER J. TERRY DEASON COMMISSIONER RUDOLPH "RUDY" BRADLEY COMMISSIONER CHARLES M. DAVIDSON
DATE:	Thursday, November 4, 2004
TIME:	Commenced at 9:35 a.m. Concluded at 4:45 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, RPR Official FPSC Reporter (850) 413-6734

DOCUMENT NUMBER-DATE
12149 NOV 15 8

FPSC-COMMISSION CLERK

A That is exactly what I'm testifying. Yes.

Q Okay. Now, now you and your consulting company provide services to your clients where you recommend actions that involve spiking meters; correct?

A Would you define spiking for me, please?

Q Well, what would be your definition of spiking a meter?

A Spiking a meter, if I took it into the end zone and drove it into the ground, that would be spiking, wouldn't it?

Q Well, why don't you turn to Page 29 and 30 of your, of your deposition.

A 29 and 30?

Q Yes, sir.

I'll read into the record, Mr. Brown, if you'd start at Page 22. My question to you at your deposition is, "What is your understanding of that term, spiking the meter'?"

Answer, "My understanding of that is that whenever you apply enough electrical load to qualify and exceed 500 kW, your rate will change."

Do you wish to change that testimony?

A I'm trying to read it, if you don't mind. Did you say Page 22?

Q 29 and 30.

A I'm sorry.

Q Page 29, begin at Line 22.

A I believe I answered on Line 22 that that's the same thing that you're trying to call spiking is calling, called qualifying a customer's account for a better rate.

Q Okay You're not changing your testimony that I read into the record from your deposition, are you?

A No, I'm not changing my testimony

Q All right. Now isn't it true, Mr. Brown, that you have made recommendations to your clients as to how to spike their meters over 100 times?

A Are we still talking about qualifying, or do we want to change the term to "spiking"?

Q Mr. Brown, I'd ask you to answer the question yes or no and give your explanation.

MR. HOLLIMON: Objection. I believe the witness is entitled to a clarification of a question if it's --

COMMISSIONER DEASON: I believe the witness is entitled to the clarification of the terminology, Mr. Hoffman, if you could.

BY MR. HOFFMAN:

Q Okay. Mr Brown, I'm going to use your definition that has been read into the record of spiking a meter, and I'll read it again.

Your deposition testimony was that that term means "that that's whenever you apply enough electrical load to qualify and exceed 500 kW so your rate will change." Now I'm using your definition. Are you with me, sir?

A Are we on Line 11, Page 28?

Q No. We're on Line 29 -- I'm sorry. Page 22, Line 29 -- Page 29, Line 22.

A Let me get there.

Q I'm sorry. Page 29, Line 22.

A Okay.

Q Over to Page 30, Line 1.

A Oh, okay.

MR. HOLLIMON: Commissioner, I'm going to renew my objection here. We're spending a lot of time on something that's completely outside the scope of this docket. I mean, if he wants to inquire about actions related to the meters in this docket, that seems like that would be within the scope and would be proper. But --

COMMISSIONER DEASON: The objection has already been made, it's been noted. This line of questioning goes to the credibility of the witness and I will allow it.

BY MR. HOFFMAN:

Q Now have you had an opportunity to read that?

A I read Line 22 through 25 and then Line 1 of Page 30.

Q Okay. Now does that provide you your definition of spiking a meter that you gave in your deposition?

A That is my definition of qualifying a customer account for the large demand rate. That's correct.

Q Now let me go back to my original question Isn't it true that you have made recommendations to your clients as to how to spike their meters over 100 times?

A I have made recommendations to my clients of how to qualify their meters over 100 times. That's correct

That -- let me go further, if I may. That also includes Florida Power & Light's customers when I worked for Florida Power & Light. That was a common practice as an energy management specialist. It was our obligation to tell our customers what was the most, most advantageous rate, particularly whenever we would make a recommendation that would bring them below the threshold of 500 on a conservation effort And not only would they save energy, but they would lose money. So it was part of our practice as representatives to identify for customers how they could regain that advantage of the rate That's true.

Q Yes sir. Is it your testimony that when you worked for Florida Power & Light, that you were instructed to advise customers how to manipulate their demand to put it over a 500 kW demand threshold level so as to not have to pay the contract rate?

A That is correct. That was not a common printed policy, but in meetings when we would bring up the fact that we were going to reduce their demand below a threshold and our effort wasn't to save them money, it was just to save energy and cost them more money. And that's --

Q I'm sorry. Go ahead.

A And, and we were instructed that you should let the customer know what rate structuring they're on and how to take advantage of more attractive rates.

Q And in connection with these recommendations that you've made to your clients that you talked about in your deposition and today as to how to spike their meters and put it over that 500 kW level, by doing that, that allows a customer to forego the requirement of contracting up to pay for the GSLD rate demand level each month for 12 months and allows that customer to get the lower kWh rate; correct?

A That would be the end result, correct.

Q Okay. So by acting on your recommendations, the customer is able to qualify for the GSLD rate because his kW demand pushes over 500 kW and he gets that lower kWh rate; correct?

A That is correct.

Q Okay.

A None of the Customers in this docket have any relationship to this. I mean, I don't know what this has to do

Q Now when I asked you at your deposition how you accomplish this spiking of meters, you refused to disclose the techniques that you use to manipulate a customer's kW demand to allow it to qualify for a lower kWh rate because your position is that these techniques are confidential; correct?

A Yes

Q So one of the main things that your consulting company does is assist FPL customers in manipulating or altering their kW demand to get that cheaper kWh rate; correct?

A That is a portion of our business.

Q Now when one of your clients is successful in spiking its kW demand above that 500 kW threshold level to get that cheaper kWh rate, that customer gets that lower kWh rate for 12 months without having to contract up; correct?

A That is correct.

Q And had that customer entered into a contract, that customer would have to pay FPL the kW demand rate for 500 kW even if the customer experienced a monthly kW below 500; correct?

A That is correct.

Q Have any of the -- excuse me. Have any of your four clients in this docket contracted up to the GSLD rate?

A I, I recently suggested that, yes.

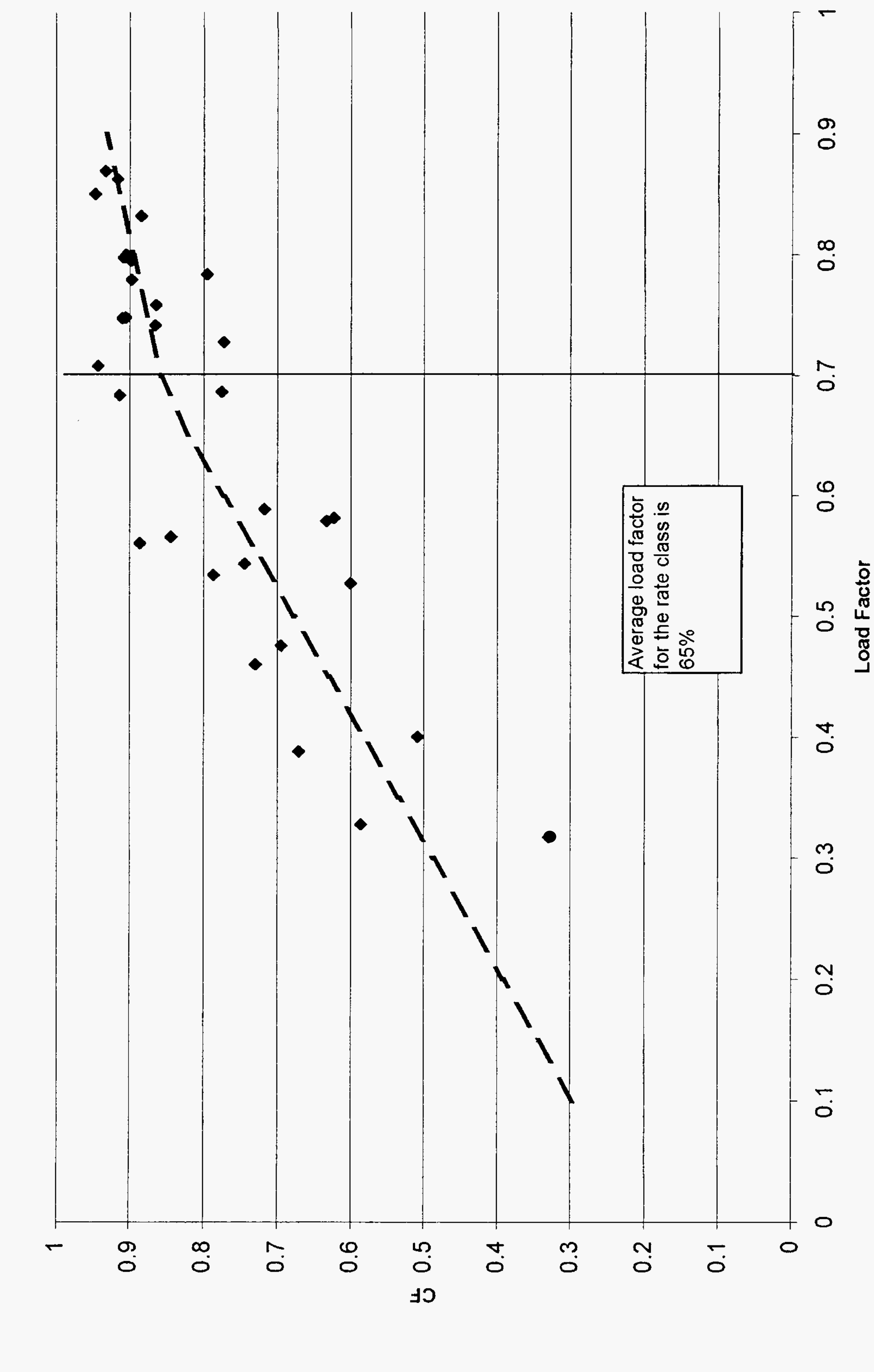
Q Have they moved forward with that recommendation?

A I haven't seen the documentation back from them

Q Would you agree that a possible result of spiking meters is that it can shift cost responsibilities from the customer who spiked their meter to FPL's remaining customers?

Docket Nos. 050045-EI and 050188-EI
R. Morley, Exhibit No. ________
Document No. RM-16, Page 1 of 1
Rate Class Coincident Factor v. Load Factor

GSLD-1 Rate Class Coincident Factor (CF) versus Load Factor



COMPARISON OF FPL TO USA
EDISON ELECTRIC TYPICAL BILL COMPARISONS
Average of Summer 2004 and Winter 2005 reports

Edison Electric Institute Typical Bill Comparison	Residential 750 kWh	Residential 1,000 kWh	Commercial 500 kW 150,000 kWh	Commercial 500 kW 180,000 kWh	Industrial 1,000 kW 400,000 kWh	Industrial 1,000 kW 650,000 kWh
FPL						
Summer 2004	64.39	86.43	11,704	13,209	28,386	40,926
Winter 2005	67.01	89.92	12,183	13,769	29,615	42,834
Average	65.70	88.18	11,944	13,489	29,001	41,880
USA						
Summer 2004	72.11	94.30	12,106	13,669	28,382	40,034
Winter 2005	70.56	91.50	11,663	13,197	27,544	38,662
Average	71.34	92.90	11,885	13,433	27,963	39,348
Difference	-9%	-5%	0%	0%	4%	6%

COMPARISON OF FPL TO USA
FPL'S COMMERCIAL/INDUSTRIAL CILC-1 RATE vs. EEI TYPICAL BILLS REPORT NATIONAL AVERAGE
AVERAGE OF SUMMER 2004 AND WINTER 2005

COMMERCIAL

Demand 500 kW
Consumption 150,000 kWh

	SUMMER 2004	WINTER 2005	AVERAGE
FPL	10,260	11,006	10,633
USA	12,106	11,663	11,885
% DIFFERENCE			-12%

Demand 500 kW
Consumption 180,000 kWh

	SUMMER 2004	WINTER 2005	AVERAGE
FPL	11,623	12,491	12,057
USA	13,669	13,197	13,433
% DIFFERENCE			-11%

INDUSTRIAL

Demand 1,000 kW
Consumption 400,000 kWh

	SUMMER 2004	WINTER 2005	AVERAGE
FPL	24,498	26,397	25,448
USA	28,382	27,544	27,963
% DIFFERENCE			-10%

Demand 1,000 kW
Consumption 650,000 kWh

	SUMMER 2004	WINTER 2005	AVERAGE
FPL	35,852	38,767	37,310
USA	40,034	38,662	39,348
% DIFFERENCE			-5%